Renewable Energy Projects: A Decade of Lessons for Financial Institutions

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Preface

This report provides background for those who might finance renewable energy projects and for those making policy decisions about incentives for renewable energy. Because renewable energy has had its share of problems, it is critical to identify those problems and how they have been resolved, and to look for ways to keep them from recurring. Ultimately, by documenting the problems that renewables have had and by noting which problems still exist and which have been solved, this report should contribute to a stronger industry.

The report is meant for a variety of audiences with different levels of understanding of the electric power industry. It is written with reference to specific, but disguised, examples of illustrative problems. Those examples and the lessons that are derived from them are the result of interviews with individuals from the financial community who have been involved in those projects. Although others may feel that different lessons should be highlighted, this report represents the perspective of one sector: the financial community. This report should be of use not only to these lenders and investors, but also to those who are interested in the financial community's perspectives on the industry.

The utility industry is enmeshed in the largest regulatory and economic restructuring that it has experienced in more than 50 years. That context informs the discussions in this report. In many cases, however, the lessons to be learned from a decade of experience in the renewable energy industry are relevant to both new and old industry structures.

Acknowledgments

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A number of people outside the financial community who have a long history of work in the renewable energy industry agreed to share their perspectives and information. In particular, Peter Banner, Michael Lotker, and Jeff King of the Northwest Power Planning Council, Don Bain of the Oregon Department of Energy, Jan Hamrin of HMH International, Ron Lehr, Greg Morse, and several other people shared insights as well. In addition, representatives of the American Wind Energy Association, the Solar Energy Industries Association, the Geothermal Resources Council and others have provided valuable background information on their technologies. Hap Boyd of Zond Systems and Darrel Dodge, Kevin Craig and Dave Renne of the National Renewable Energy Laboratory reviewed the document, providing valuable comments and suggestions for improvements.

Although the insights of these and others too numerous to mention were valuable, any misstatements or errors ultimately rest with the author.

Executive Summary

With declining costs and improving technology, one would expect the renewable energy industry to be in good shape and poised to grow at unprecedented speed in the mid-1990s. Yet, fewer renewable energy projects are being built now than 10 years ago, when the technology was new and expensive. Today, domestic renewable energy is in some trouble. Much of the problem that renewable energy faces has to do with a general upheaval in the utility industry that has the potential to shut out these capital-intensive projects. Some of this trouble relates to a collective legacy from past problem-ridden renewable energy projects. This report describes these problems in specifics and notes, as well, how they have or have not been addressed.

The financial community views fuel and resource assessment as the paramount issue with renewable energy resources. Most investors or lenders would, in fact, prefer to rely on a long-term fossil fuel contract than a long-term promise of wind, water or sunlight. The unhappy experiences in the late 1980s appear to provide ample fodder for doubts about renewable energy. Yet the techniques for measuring wind or other renewable resources are far better now than they were during construction of the early renewable energy projects. It is clear now that resource assessment techniques are much more sophisticated and precise than they were. It is now clear that resource assessment techniques have limits; they cannot predict climatic events that change the inter-annual availability of resources. Financial terms may need to allow for the predictable variability of wind or other renewable resources.

To some extent, technological issues have been responsible for adding renewable energy projects to the financial institutions' "watchlist" of projects. Wind, in particular, has developed new capabilities that have allowed the turbines to operate in harsh or mild wind conditions--and to produce power far more regularly than they once did. Many early problems were related to tax incentives that encouraged developers to focus on building--but not maintaining--wind projects. Some of the early problem-ridden projects that became well known were experimental and used one-of-a-kind technologies for which replacement parts were difficult to find. Some simply were poorly designed for the environment in which they were operating. Many of the technological issues have applied to the newest of the utility scale technologies, wind, rather than to other more conventional technologies such as hydro.

Investors with short-term interests dominated the renewable energy industry during the early 1980s. Motivated by tax considerations, many of these investors and developers built for short-term returns and had little incentive to maintain wind, solar or other renewable energy projects. As the early tax incentives disappeared, so did the less credible developers. Some of these developers have survived the demise of the tax incentives. These companies, in general, remain the stronger developers in the industry. The incentives also were responsible for much of the innovation in technology and the development of the industry today. By and large, however, the greatest barriers to renewable energy resource development have been related to new technologies and to resource assessment.

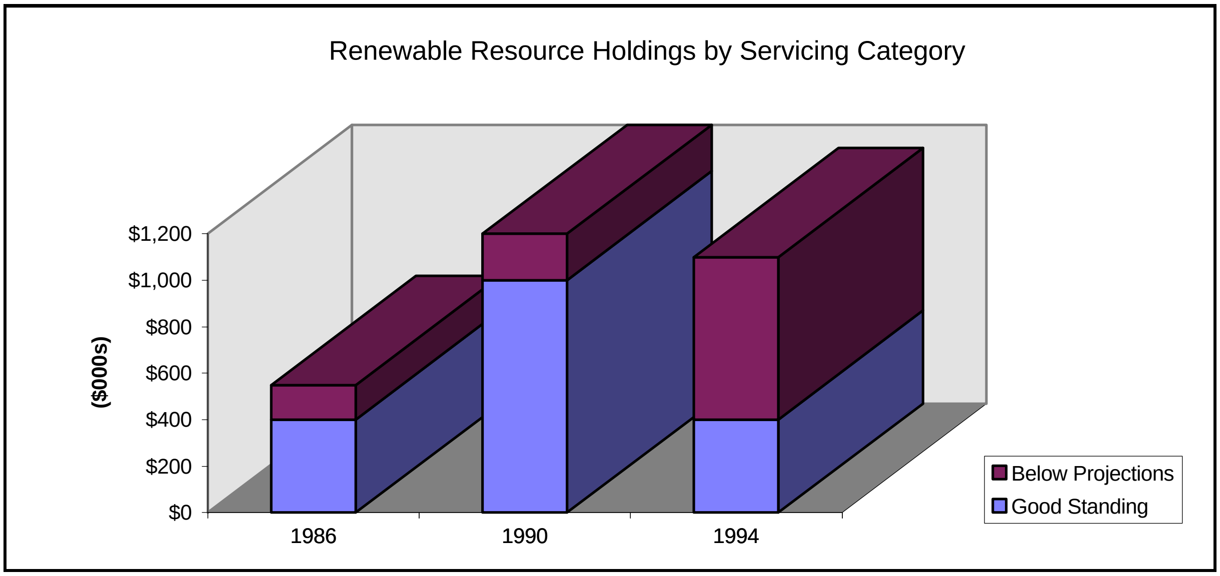
Background

In February, 1994, a group of lending institutions, equity investors and investment banks assembled to discern the barriers that the financial community saw to renewable energy resource development. Renewable energy is here defined as any electric power plant that does not use fossil fuel to produce electricity. Typically, renewables include wind energy, solar energy, hydro power, geothermal and biomass resources. Renewables sometimes include municipal solid waste resources; for simplicity's sake, we include such power plants under the general category of biomass. Among the financial barriers to the use of renewable energy, one was paramount: renewable energy technologies have a poor reputation with many people responsible for financing them during the early years--through the 1980s and early 1990s. This poor reputation is largely due to a minority of "problem" projects that have besmirched the overall reputation of renewable energy projects.

In fact, the vast majority of renewable energy projects posed few problems during this time. Poor perceptions create their own reality, however, and the perception remains that many renewable energy technologies are problematic. This has forced renewables to seek "credit enhancements." That is, renewable energy project developers usually have to provide more of their own money to build a project, may have to commit to financial guarantees that their project will perform, and will almost always have to pay a premium rate on their loan. This premium rate can easily be one or more percentage points above that which a developer using more conventional resources like oil, coal or natural gas would have to pay.

One company, Prudential Power Funding (one of the largest investors in independent power projects), has performed a careful analysis of its renewable energy projects to determine which are on the "watchlist" or are in "workout," which are performing below expectations, and which are doing well.[1] The results indicate that renewables have indeed been more problematic than conventional electric generation facilities. Indeed, as some of the projects have aged and the regulatory or legislated incentives that bolstered their revenues have disappeared, the number of projects operating below revenue expectations has increased. This high proportion of projects operating below expectations is characteristic of renewable energy facilities. It is important to note that this graph also represents projects that were brought on line some years ago; the new generation of some renewable energy technologies work better than did these older projects.

[1] Projects on the watchlist are those that have shown some warning signs of possible trouble; they may, for instance, have fallen below a standard in the ratio of revenues to debt service. Projects in workout are those with problems that currently are being "worked out" or resolved.



Standard and Poors and the National Association of Insurance Commissioners (NAIC) both rate projects. The NAIC ratings are particularly relevant to insurance companies, who are the major investors in renewable energy projects. Insurance companies cannot maintain more than a certain percentage of below-investment-grade projects without a higher level of capital required to back those investments. In general the grades are as follows:

Insurance Company Capital Requirements

S&P	NAIC	Capital
A-AAA	1	1%
BBB	2	2%
BB	3	5%
B	4	10%
Below B	5	20%
Default	6	20%

Investment Grade Projects

Below Investment Grade Projects

Most renewable energy projects fall into the below-investment-grade area. Below investment grade investments are not bad investments; rather, they present a higher risk than investment grade projects and thus require higher returns than low-risk investments. The fact that renewables are often seen as higher risk investments imposes stiffer requirements (seen in the terms, conditions, structure and documentation required for such transactions) on investors and developers alike.

Some of the problems of these early projects were rooted in the fact that renewable energy technologies and the companies that built them were new. Some of these problems disappeared as the industry matured; others remain.

Growing Pains and Lessons Learned

Many of the experiences from the 1980s reflect the growing pains of a new industry dealing with new technologies. The period beginning in the mid-1980s and ending in the mid-1990s has been characterized by a maturing, but still nascent, renewable energy industry. The incentives to build renewable energy facilities had an enormous effect in the early part of this period but, because those incentives were reduced, the second half of the 1980s marked the beginning of a shake-out in the renewable energy industry. Many companies that had developed projects for the tax benefits alone could not survive.

The government incentives, the early state of technological development, and the inexperienced companies shaped the early renewable energy industry. It is in this context that many of these lessons appear. The challenge is to identify which poor experiences from the past are likely to occur again, and which will not. Even further, the challenge is to learn from the lessons provided by growing pains of the 1980s and early 1990s.

The Financial Community and Renewable Energy

The financial community's understanding and perspective is colored by one question: will the investors and lenders earn the return or receive the interest payments that they expect? Senior and subordinated lenders, equity investors and investment bankers look at renewable energy projects in distinct ways. Investment bankers expect to make a commission, lenders to receive long-term and fixed payments and equity investors to earn a shorter term payback and return. Each of the players in these deals must do its own due diligence -- or examination of the project before committing money to the project. This process of due diligence is important and expensive, requiring the financial community to have an excellent understanding of the technologies and the markets with which it is dealing. Ultimately the investors and lenders attempt to strike a deal that allocates risks to the party best able to handle them, that provides ways to measure the project's performance and that gives some monetary safeguards to project investors and lenders.

Sometimes such safeguards are insufficient and the due diligence are unable or inadequate to predict the problems that a plant will experience. Such occasions engendered this study.

Lessons Learned

Caveat: Almost every utility scale renewable energy project that has been built in this country has used the private placement market to gain access to financing.[2] Private placements are by their nature private and confidential. We assured each person from the financial community who supplied us with information that we would describe projects generically. We reference renewable energy projects according to their technology and the region of the country in which they were built. This generic reference should not interfere with the basic goal of this report: to glean a series of lessons that can be learned from the past decade of renewable energy projects.

These discussions focus on utility scale energy projects. They do not deal with small power systems such as rooftop solar water heating or photovoltaics. In some cases (such as discussions of the project developers and regulatory issues), the discussions and examples are generic and can apply to any renewable energy technology. In other cases (particularly in discussions of technology or fuel resource assessment), they are broken down according to the renewable energy technology.

In general, the types of lessons that can be gleaned from more than 10 years of experience with renewable energy projects fall into four categories: fuel and resource assessment, developer responsibilities, regulatory issues and technological issues. Where it makes sense, we separate the lessons according to the technology to which they apply.

The vast majority of the lessons, from the perspective of the financial community, are related to fuel or renewable resource characteristics. The other categories of “lessons learned” are important--but less so. Regulatory issues determined the shape of the early renewable energy industry. Most of the regulations affected both fossil and renewable energy resources, albeit somewhat differently. Developing technology has also been important, particularly for wind energy. Yet, once again, many technological developments have been closely tied to fuel -- the ability to measure wind resources. New wind turbine developments have been dramatic and important. Yet from the perspective of the lenders and investors who provided capital to these projects, the early problems with measuring or estimating the wind resource were paramount. Other renewable energy resources such as geothermal, hydro or biomass have had fewer technological issues.

Finally, the large incentives that some states and the federal government offered to developers of renewable energy resources attracted a number of opportunistic people to the renewable energy field during the mid-1980s. Those incentives have been removed or altered and the industry has changed dramatically for the better, as a result.

[2] This statement does not include large scale hydro projects built by large public power entities.

Fuel and Resource Assessment

Resource assessment, or the process of determining how much wood, wind, water or other fuel is available to feed into power plants, has probably been the greatest single barrier to the early development of renewable energy resources. Resource assessment is also one area in which renewable energy developers have made notable progress.

In the area of wind energy in particular, resource assessment tools and methodologies have developed rapidly. Some experiences with resource assessment in the biomass and geothermal area also should prove instructive. Notably, however, the advances in wind resource assessment are related in part to computers and technological advancements, while the advances in assessing the resources available to other renewable technologies are a result of improving assessment methods and more experienced developers. The financial community cites fuel and resource assessment as the most significant stumbling block to lower cost investments for all renewable energy technologies. Based on the experiences of the early industry, their concerns have been warranted. Although many of these problems could recur, if developers and the financial community learn from their mistakes, they need not.

Biomass

Every fossil fuel fired power plant must have a long-term contract to buy natural gas, oil or coal. Financing agreements require that the plant have such a long term contract. Such contracts do not exist for renewable biomass resources. Lenders and investors are forced to rely instead on other more tenuous guarantees.

Companies that supply wood or other biomass to power plants are almost never in a position to sign long-term contracts to supply fuel. The suppliers may be lumber mills or orchards or some other industry that generates combustible wastes. But the suppliers are rarely in business solely to sell fuel to power plants. As a result, the usual length of a contract for biomass is seven years or less; by contrast, a developer could sign a natural gas contract for 15 or more years.

Developers and the financial community rely instead on generalized assessments of the supply of fuel that is readily available to a plant. In the case of biomass, a developer might have to prove that a certain amount of fuel is available within 100 miles. Uncertain fuel supply causes lenders and investors to be wary of financing biomass projects.

Biomass Power Plants Need a Secure and Adequate Supply of Fuel; Developers and Financial Institutions Must Analyze the Impact of Other Demands on Biomass Fuels

One power plant built in the northwestern United States used agricultural wastes (including almond hulls, grape stalks, orchard prunings and peach pits) to fire its burners. These fuels were to have been provided free of charge. They would otherwise have been thrown away and apparently had no alternative uses. The developer of the plant estimated that his power plant could secure approximately 50 percent of his supplies from these sources. In reality, only 5 percent of the plant's needs could be secured from these sources. The developer had to purchase wood and other substitute fuels from the commodity market at prices far above the nominal prices he had expected to pay for the agricultural waste.

Another project in the same part of the country received financing on the basis of very low fuel costs. The lender assumed that, even if the fuel price increased by an unthinkable 50 percent, the plant would still be able to pay its debt service. In fact, for reasons described below, the price of biomass fuel skyrocketed. The plant could not make its debt payments and was sold for approximately 20 percent of its book value. The utility that had been buying electricity from the plant now finds it cheaper to pay the developer not to run the plant.

Many biomass projects on the west coast suffered from a rapid rise in the price of their fuel. A similar but less serious situation also arose in the Midwest.

The problem: Each company had projected how much fuel it would need to produce electricity, but none of those projections took into account the fact that other biomass-fueled power projects would begin operation at the same time. Fuel suppliers that might previously have been willing to pay to have their refuse or fuel removed from their property now saw an active market for their wastes. This new demand for biomass fuel put a tremendous strain on the supply of a previously free or inexpensive commodity, and the price leapt upwards.

The west coast biomass problem was close to a decade in the making. Beginning in the early 1980s, with attractive tax benefits and specialized contracts for renewable energy, a number of companies began to see an opportunity to produce power using wood or food processing residue. Many of these companies built small (5-10 megawatts) plants to serve their own heat, electricity and steam needs.

As the benefits of the specialized--or so-called standard offer--contracts and reduced taxes became clear, additional plants entered the market. Instead of relying on wood wastes from their own facilities, as some of the early lumber mills had done, many of these companies set up contracts with other fuel suppliers including sawmills, farms and orchards. Orchards, for instance, would sell the branches that they trimmed from their fruit trees. The owners of the orchards were pleased that they had an easy way to dispose of their waste. Instead of burning the trees and branches, the power company would truck them away.

During the first half of the 1980s, the demand for agricultural waste or sawmill residue quadrupled. The supply was able meet this demand with little problem. By 1986, the number of new biomass facilities in the state grew even more rapidly, at an average of 155 MW of new power plants per year. The fuel requirements for these facilities grew by an annual amount that was 50 percent higher than the total demand in 1980. By 1990, the demand for biomass fuels was 14 times what it had been only 10 years before. Power companies were forced to search for new sources of fuel because their previous sources were no longer available.

This constricted supply created logistical problems for the companies that needed new sources of fuel. Even more serious were the economic problems. Most plants were built under the assumption that they could purchase biomass fuel for between $15 and $20 per ton. Now they were paying more than $50 per ton. Many of the facilities could not operate at those costs. The financial institutions that had supported the plants began to see loan defaults. Equity investors faced the loss of their investments.

By 1994, approximately one-sixth of the 56 biomass facilities that were operating in the state at the beginning of 1990 had shut down. Some remaining companies found new sources of fuel, for example, waste wood that would otherwise have gone into a landfill. With a somewhat decreased regional demand and a new source of fuel, the industry began to recover. Fuel prices decreased to $30 per ton. The healthier companies were able to survive, although not as well as they might have under the price regime forecast when they built the plants.[3]

There have been few technological advancements to offset this rapidly escalating increase in the price of biomass fuels. Federal laboratories and others have continued to develop energy crops, including grasses and short rotation woody crops, and are exploring the use of plantations for dedicated long term fuel supplies. Still, the contracts to supply biomass remain relatively short-term. But this situation will not recur if developers and the financial community measure not only the demands on their fuel from their own plant, but also forecast the demand that other power plants might place on the fuel supplies. Good forecasting is an essential element of managing these short-term contracts. This remains an important issue that can be avoided through careful forecasts.

[3] Gregory Morris. (December 1990). *The California Biomass Energy Industry in 1990: Supply, Demand and Outlook for Biomass Fuels.* Berkeley, Calif.: Future Resources Associates, Inc.

Biomass Power Plants Should Have a Performance Test With the Fuel They Are Most Likely to Use During Ordinary Operation

"Spec" fuel describes the quality of the fuel that suppliers contract to deliver to developers. Developers generally ask that fuels have a certain energy content, and may make other specifications (such as the consistency of the fuel) as well. The specifications of the fuel, particularly its energy content, are part of the developer's calculations for specifying what equipment he needs to produce electricity.

In one project in the western United States, the developer designed a 20 MW power plant under the assumption that he would receive "spec" fuel. This assumption was justified by a contract that delineated the characteristics of the fuel he wanted. He tested the power plant successfully with the spec fuel. The lender was satisfied, and committed to the term loan. In day-to-day operations, however, the plant rarely received fuel that met the specifications. It frequently had a moisture content that was several percentage points above the specifications. As a result, the power plant rarely produced the amount of electricity to which the developers had committed.

Because biomass fuel suppliers often supply fuel only as a secondary or even tertiary business activity, "spec" fuel does not always exist in practice. Power plants should be tested using a broader range of fuel. Such problems will not recur if developers and the financial community develop terms that anticipate the variation in the energy content of the fuels that power the generation stations. Developers and the financial community may consider making revenue projections for the project based on the possibility that the plant is forced to use low quality fuel for some of its operations.

Biomass Projects Should Rely on Nearby Sources of Fuel

One biomass project in the northwestern United States developed its cost projections on the basis of an inexpensive source of forest trimmings located nearby. In reality, the amount of forest trimmings available was adequate to supply 50 percent of the power plant's needs. The plant operator had to travel much further to secure the necessary amount of fuel needed for the power plant. The cost to truck in this fuel from further away far exceeded projections, and the plant had major problems in paying its debt service.

Biomass--particularly biomass that consists of orchard tree trimmings, wood chips or other bulky waste products--is expensive to transport. It rarely is bone-dry and often is mixed with non-combustibles. Moreover a large number of trucks are required to move it from source to power plant. One 36 MW plant that used forest residue would burn more than 52 tons of wood each hour, or 400,000 tons of wood chips each year. If the facility ran 365 days per year, it would need 45 to 50 forty foot truckloads daily. To compensate for days when the trucks might not be able to deliver, the power plant would need to store wood on site. In addition, the plant should be prepared to take in fewer truckloads on some days and more on others; it would actually require the capacity to receive up to 70 truckloads daily.

With this number of trucks, the cost of diesel fuel is a major determinant in the economics of biomass power plants. As a general rule, the fuel sources should be located within a 100-mile radius of the power plant. Resources that are further away will have higher transportation costs, which reduce project profits. As with many biomass fuel issues, this problem will not recur if the developers, lenders and investors understand how the cost of transportation affects the economics of the power plant and incorporate this into the project plan. To the extent that more efficient power plants will also decrease the amount of fuel required to produce kilowatts of electricity, this is also an argument to use the most efficient technology available.

Biomass Projects Should Use Fuels That Have Been Thoroughly Tested in Power Plants

With the constricted supply of biomass fuels, some developers began to experiment with new fuels. Not all of them worked. One western United States power plant burned rice hulls in its boiler. Built in California, the plant appeared to solve a problem for the rice industry: the disposal of rice hulls. However, burning rice hulls proved to be unworkable. The silica in the hulls caked the inside of the boiler, ultimately destroying the boilers.

Another respected developer saw an opportunity to burn animal manure in a power plant. The dried feces met many of the criteria of a good fuel; it was uniform, plentiful, inexpensive and easy to transport. Yet, when the feces became wet again during processing, it became clear that the developer had not performed a complete chemical analysis of the material. The urea and uric acid ate through the tubes and equipment in the boiler system. Even when the developer rebuilt the system with stainless steel, the problem persisted.

These problems will not recur if the developers subject the new fuels to a rigorous analysis of their behavior in the power plant. The analysis should examine how fuel will be stored, processed and burned.

Other Issues Related to Biomass Fuel

With the exception of plants that burn municipal solid waste, biomass projects involve more fuel handling costs and processes than any other electric generating technology, renewable or otherwise. Biomass projects must not only locate a secure supply of fuel, but they often must also separate it (if the fuel includes a mixture of combustibles and non-combustibles), store it, and feed it in proper ratios into the power plant's burners. Moisture is also an issue. Where coal might absorb 10 percent to 20 percent of its weight in moisture, biomass could absorb up to 60 percent of its weight in moisture, which can dramatically decrease the efficiency of the boilers. This has, at times, required considerable capital investments for fuel handling, emissions and storage.

The uniformity of biomass fuels also is important. (See references above to variability in heat content of biomass fuels related to "spec" fuel versus actual fuel, and to storage of fuel and its resultant moisture content.) The uniformity and predictability of the biomass fuel stream will determine the efficiency of the power plant and its ability to produce electricity at the contractual rate, unless the variability is factored into the plant design.

Geothermal Resources

All operating geothermal power plants in the United States use the Rankine Cycle. The types of systems can be broken down into four general types: direct steam, flash steam, binary, and hybrid steam/binary systems. Direct steam systems used at dry steam hydrothermal resources are the focus of this discussion. At dry steam sites, the geothermal power plants do not use boilers in their electricity production because the water is vaporized below ground. After screening debris, the dry steam is processed through the turbine. Dry steam geothermal resources are rare, even though they accounted for most of the early projects.

Early US geothermal resource developments were located at dry steam resource sites, and geothermal developers sold the steam directly to utilities. The initial contracts between the geothermal resource developers and the utilities decidedly favored the utility. For example, the price of steam could be no more than the weighted average of nuclear fuel cost and two-thirds of the price of fossil fuels. Moreover, the contracts had no price floor. Because there were no capital investments for boilers, the capital costs for these geothermal power plants were less than those of traditional fossil fuel power plants. Thus, the utilities pursued the lowest cost (non-resource preserving) use of the geothermal asset. This lead to inexpensive (but inefficient) power plants that consumed up to 40 percent more geothermal steam than other more resource efficient geothermal power plants. This inefficient use of the resource became a problem later when it became clear that certain fields began to lose reservoir pressure because of overdevelopment.

This situation was made worse by pricing clauses in some early contracts. Contract clauses annually adjusted the price paid for steam; when the price for natural gas or nuclear fuel rose, the price for steam rose. Some historic contract pricing formulae were constructed so that when the price of steam rose or the amount of production increased, the value of the steam field increased geometrically. When the price decreased, the value of the field responded accordingly. Thus, due to the nature of the contracts themselves, the geothermal industry was subjected to wide variations in the value of its assets. This led to rapid expansion during favorable pricing periods and profit crunches in unfavorable times. Consequently, developers attempted to increase profits during the good periods, which contributed to a short-run profit taking orientation in geothermal field development.

Geothermal steam fields declined in value even though installed generation capacity increased. This decline can be attributed to two major developments. First, the geothermal producers experienced a significant decline in the price of steam which was contractually determined between the geothermal developer and the utility. Between 1985 and 1987 the decline was greater than 50 percent as a result of decreases in the prices of fossil fuels, to which the price of steam was tied. Second, there was a significant decrease in reservoir pressure and its corresponding geothermal production. This has been attributed to the over-production and over-development of certain geothermal fields.[4] Although some improvement has occurred, (primarily due to developments in fluid reinjection technologies and methods), the fields operate below installed capacity levels. For example, 1,736 MWe was produced in 1994 from an installed capacity of 1,990 MWe.

[4] William P. Short III. (November 1991). "Trends in the American Geothermal Energy Industry." *Bulletin*, Geothermal Resource Council, pp. 245-257

Geothermal Wells Should Be Far Enough Apart to Maintain Limited Resources in an Area

Geothermal resources rely on very hot steam that is found, under high pressure, beneath the ground in certain parts of the country. The resource generally is located in isolated pockets, so that one well drilled too close to another can impinge upon the hot pressurized steam available to another well. Unfortunately, the location of the steam can not always be pinpointed. Much like an oil well, developers sometimes must drill exploratory wells to find a suitable source of hot steam. Once the source is located it is not always clear how close by new wells can be drilled.

One western geothermal field appeared well suited for a great deal of drilling. The field was so attractive, however, that the wells that were drilled began to impinge upon each other. The pressure in existing wells dropped as new wells were sunk nearby. Eventually, an agreement among the various companies with rights to the resource resolved this problem.

Geothermal Steam Reinjection Wells Should Not Be Drilled Close to Production Wells

The sources of hot steam that turn the turbines in a geothermal electric power plant can be depleted over time. It is common, however, to replenish the geothermal resource by reinjecting steam into the underground pocket. One geothermal facility in the northwest United States drilled its reinjection wells so close to its production wells that the lower temperature of the reinjected steam began to affect the temperature of the production wells. Where the temperature of the steam reinjected into the reservoir ranged between 250 degrees and 260 degrees, the temperature of the production well steam was approximately 320 degrees. This company solved its problem by drilling new reinjection wells further from the primary well, although the company only accomplished this at a cost of more than $3 million per well.

As with many fuel-related issues, these problems could recur; they have not been resolved with new technologies. Rather, their resolution depends upon a knowledgeable and experienced developer who understands the characteristics of the geothermal resource.

Hydro

One of the best understood renewable resources, hydro technology and its resource assessment has benefited from years of large-scale utility projects. Hydro is also a fairly simple technology: water turns a turbine. So long as the turbine is sized to match the speed and flow of water, hydro projects encounter few problems. As with many renewable energy technologies, an accurate analysis of the resource remains the key to successful projects. Fast-flowing water suggests a large turbine that will generate more power than a smaller turbine, while an oversized turbine in slow-moving water may not turn at all. Resource assessment is critical for hydro projects. A few experiences illustrate some important lessons from recent experiences with hydro power.

Hydro Resource Assessments Must Be Taken Where the Dam Will Be Constructed

Hydro project developers attempt to predict how much, how high, and how fast water will pass through the turbines. Over-estimating the flow of water that passes through the turbines could mean that developer selects an oversized turbine, one that slow-flowing water cannot turn.

A rigorous assessment of the water flow was conducted before construction of a western hydro facility in the 1980s. The assessment of the amount and speed of the water flowing down the channel on which the hydro turbine was placed was used to size the turbine. A larger turbine would produce more electricity, but would also require a more active stream flow.

The developer, however, measured the water flow on one branch of the river; the hydro power facility was to be built on another branch of the river, where the water flow was barely sufficient to turn the turbine. As a result, the turbine had to be replaced at considerable cost and delay. This situation reflected a lack of understanding of the great variation between sites that are located close to one another. Micrositing and resource assessment are as critical, if not more so, with hydro as they are with other location-specific renewable energy technologies.

Hydro Resource Availability Varies from Season to Season and Year to Year

All hydro projects are subject to seasonal variations in rainfall and drought. Water resource assessments represent averages over a number of years. So, by definition, an average of water flows means that some years will have more than average and some will have less than average water flows. Hydro plants thus can generate more power (and therefore more revenue) during years of greater water flows and less revenue during years of lower water flows. This issue remains important and reflects a basic characteristic of the hydro resource. Ultimately, financing terms and conditions, as well as power purchase agreements, may need to take into account this annual variability.

Wind

No renewable energy technology has developed so rapidly as wind. In price alone, the cost to generate electricity from wind turbines fell by 85 percent between 1980 and 1995. The price of power from wind turbines is now competitive with that of some fossil fuel technologies. A great deal of this development is the result of ever more sophisticated techniques for measuring the wind.

The Wind Resource Should Be Assessed in Detail

Early wind projects often underperformed because of poor wind data. These projects relied on assessments of the average wind speed in an area. Simple averages were not useful, however. The specific location of wind turbines, the height of the towers on which they are mounted and the proximity to other turbines are very important factors. Early projects used only crude estimates or relied upon data that was not representative of the site. Developers built their turbines in areas with excellent average wind speeds, but found that the turbines underperformed. Small variations in terrain, the location of nearby wind turbines, and even the height of wind turbines could result in problematic turbulent winds. Such variations had the potential to make individual wind turbine sites either very attractive or quite unattractive.

It is important to collect wind data so that it can be "binned" to indicate the percent of time the wind is blowing in various wind speed categories (1-2 mph, 2-3 mph etc.). A turbine then can be designed and sized to optimize energy production for specific wind regimes. Today, accurate on-site wind measurement using anemometry and high-speed computers have reduced the guesswork in turbine location. Based upon wind information carefully gathered over substantial periods of time, the entire "wind regime" of a site can be simulated and turbine siting can be optimized. Very gusty winds require hardier equipment than steady winds, for instance.

One project built in Hawaii in the 1980s is typical. With less than 50 turbines and the theoretical capacity to produce 12.5 megawatts of power, the project never actually produced more than 6.5 megawatts. Many of the problems in this Hawaii project had to do with a poor assessment of the wind resource. At another location where the wind had been measured at an average speed of 19 miles per hour at a specific location, it blew instead at only 17 miles per hour at the wind turbine sites. As a result the project generated 14 percent less power than predicted.

The same project illustrates another problem with wind data; the so-called "array effects." Siting turbines too close to one another reduces the speed of the wind available to the downwind turbine. In the Hawaii project the wind turbines were arranged in rows of three. Because of this array effect, the speed of the wind at the last row of turbines was 60 percent lower than the speed of the wind at first row of turbines. The first row of turbines used the full wind resource, just as it had been measured at the site. The second row and each succeeding row had diminishing wind speeds.[5]

Project developers also found that in some locations building a wind turbine on a 150-foot tower--instead of on a 30-foot tower--could double or triple the amount of wind power available to the turbine.[6] The height at which the wind turbine is placed is significant because wind speeds usually increase with height above ground.

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[5] Hubbard et al., *Advances in Solar Energy*, "Wind in Hawaii," p. 450.
[6] Paul Gipe, *Wind Energy Comes of Age*, Island Press, p. 150.

Developers now are far more skilled at measuring wind resources. With support from the U.S. Department of Energy, developers and some state agencies are beginning to collect detailed wind data that can determine the best possible sites for wind projects. Computerized wind measurement tools also are helpful in this effort. It is now standard practice in complex terrain to measure not only the average wind speed in an area, but also the wind speed in the "microsite"--at the height and precise location where the turbine will sit. Such detailed measurements are valuable in hilly or otherwise complex terrain, but probably are not necessary on flat plains, for instance, where there are few obstructions to the wind.

The Inter-Annual Variation of Wind Can Hurt Project Economics

Wind power projects, like hydro, rely on resource assessments that document both a detailed and an average wind regime in the area where developers propose to build their wind turbines. The wind plants rely on a somewhat predictable wind resource to turn the turbines. The ability to measure the wind resource has increased tremendously during the past 10 years. Nonetheless, no matter how good the wind resource assessment, it remains a prediction. These predictions have been able to accurately forecast the variation of the wind from one season to another. They cannot, however, predict climatic variations from one year to the next that may result, for instance, from shifting atmospheric conditions. In one year the wind may blow more than another. This variation means that wind plants will generate more power and more revenues in windier years and less revenues in less windy years.

This risk will not disappear from wind or other renewable energy projects. The risk may, however, suggest that financing terms for renewable energy resources should be more flexible to allow for this yearly variation. Developers and financing institutions need to build this flexibility into both siting and financing for wind power projects.

Developers

Some lessons from the past decade of renewable energy projects have little to do with the technology or the renewable resource. They are instead, related to the character of some companies that were involved in the early renewable energy industry. The short-term incentives that were offered to early renewable energy developers attracted developers with a short-term focus. This short-term focus often meant that the developers were more interested in making money from a short-term investment than they were in constructing a project to produce energy and revenue over the long-term. These early, short-term incentives and the short-term focus resulted in some projects that performed poorly and focused the attention of the financial community on developers of renewable energy projects. Because the early problems with developers are generic to all technologies, the following section is not separated according to renewable energy technology.

Reliable and Committed Developers Are Critical to a Successful Project; Tax and Incentive Structures Can Attract Less Reliable Developers

Many early problems with renewable energy resulted from project developers who were responding to tax incentives that held little incentive for them to build a solid, working project. In the early to mid-1980s a developer could build a $100,000 project by borrowing $90,000 and investing $10,000 of his own money. State and federal tax credits then would offer $37,500 in tax credits whether the project worked or not. Additional five-year accelerated depreciation schedules and other incentives made it a highly attractive market for those with short-term, non-market interests. Although power sales contract and debt obligations were of longer duration, the equity investors had little incentive to maintain the project once they had earned the return they expected during the very early years of the project's life. With the disappearance of many state tax credits (and the restructuring of the federal tax credits to provide benefits only if the wind or biomass projects produced electricity), most of these problems have been resolved.

Motivated by these short term tax advantages as many of the early California developers were, early wind farms did not perform as well as they should have. These incentives to build, but not maintain, wind farms left many nonfunctioning wind turbines in California. After recouping the initial investment, there was little incentive to maintain the wind turbines running. One person involved in the early California wind industry described the time as dominated by a "land rush" mentality. Illustrative of the frenzied pace of the deal-making was the rapid rise in brokerage fees to put together wind financing deals; where they had typically been set at 10 percent of the value of the deal, they shot up to 25 percent.

The frenzied pace of the market encouraged people to put up wind power plants with only three months of data on how fast and when the wind would blow. Today, gathering data for a year, two years and more is more common. Some deals were signed with no wind data that was specific to the site where the turbines were being built. Accusations have been made that some companies inflated the wind data by 20 percent or more to show that they had a viable project.

In the frenzy to acquire the benefit from these tax advantages, the financial community was not blameless. One consultant, for example, reported to an investment firm that the wind resource was not nearly as good as the developer had presented to the financial concern. Yet, the investor signed the deal anyway; his interest was in the tax benefits.

A number of people interviewed noted that, once an area was identified as having an ample wind resource, it was assumed that the entire area had the same resource. One wind company, for instance, correctly identified the Tehachapi area of California as a part of the state with an excellent wind resource. The developer quoted average wind speeds of more than 18 mph--ample for even the wind turbine technologies of the early 1980s. The next developer who attempted to secure financing in the area found that financing a wind farm at anything less than an 18 mph average estimated wind speed was impossible. The incentive to overestimate wind speed data was great and often present.
Some early California developers felt compelled, because of the land rush mentality of the day, to rely on wind data collected by the California Energy Commission. Such developers felt that taking the time to gather highly site-specific wind data would make it impossible to take advantage of time-limited tax and contractual incentives. The Energy Commission's data could not be extrapolated to every site, however. Now developers collect their own site-specific data. Few of the tax incentives remain, and those that do are granted only if the wind turbines actually produce energy. The tax-generated motivation for the land-rush mentality of the mid-1980s no longer exists. The industry has consolidated, and only a few far stronger companies remain active.

The Developer's Business Should Be Focused: The Developer Must Be Able to Do What He Says He Can.

Developers of various renewable energy technologies have attempted to take on the roles of developer, construction firm, operation and maintenance firm, and technology developer. This level of vertical integration and diffusion of focus may be too much for one company to take on if it does not actually have the capability to perform all these tasks.

One wind developer, for instance, offered a turn-key contract option for its contracts. The company's focus was on developing turbines, however, not in setting up wind turbines at customer sites. Even such details as renting a large crane to set up the wind turbines (at a cost several thousands of dollars each day) was daunting, and ultimately led to cost overruns for the company.

One company that had for several years owned a power plant that used biomass witnessed a quick and substantial rise in the price of timber during the early 1990s. Although the power company had little expertise in running one, it elected to build a lumber mill next to the power plant and to use the pulp, sawdust, bark and other residue from the mill as feedstock for its power plant. The company bought used sawmill equipment for slightly more than $2 million. The equipment never worked, however, and the power plant continued to supply its fuel needs from the commodity market for waste wood products.[7]

Ensure That Conflicts of Interest Between the Developer and the Firm Performing the Operation and Maintenance Do Not Result in Inaccurate Cost Projections for O&M

[7] A number of biomass developers have suggested that they could grow their own crop as a feedstock for their power plants. Although the control that burning one's own fuel offers is attractive, it is also a distraction from the primary business of the company, i.e., generating electricity. A company is, in other words, becoming a farmer in addition to a power plant developer. Instead, joint ventures may be a successful way to ensure a fuel supply.

It is not inherently bad that the same entity both develop the project and perform operation and maintenance. Yet, it can be a source of problems. In one case in the western United States, a developer proposed a project that incorporated seemingly low operation and maintenance costs. Although the project was accepted for financing and received a utility power contract, the operation and maintenance costs had been underestimated. As a result, the project encountered problems in meeting its debt payment obligations.

This conflict does not always present a problem, but the lack of separation may be an indication for the financial institutions to look more closely at operation and maintenance figures during the due diligence process.

Regulatory Issues

Regulations and legislated incentives have created a market for renewable energy since the late 1970s. As those regulations have changed, so has the renewable energy market. Indeed, as the electric industry continues to change, the market for renewable energy will change with it. Yet, the changing regulations have affected more than just renewable energy; they have affected the independent power industry as a whole.

Federal Incentives

Following the oil price shocks and the OPEC oil embargo of the 1970s, the federal government instituted the first major change to energy industry regulation since the 1930s: the Public Utility Regulatory Policies Act, or PURPA. This 1978 legislation was directly responsible for spurring much of the renewable energy resource development that now exists in this country.

PURPA offered special consideration to small developers of electric power plants that used renewable energy. The most important of these considerations was a requirement that all utilities purchase power from these small power plants at "avoided costs," or the cost that the utility would otherwise pay to generate power from its own facilities or purchase from other sources. Usually these avoided costs were calculated using estimates of the utility's fuel and capital costs. They generally were projected over a period of up to 20 years and, in the 1980s, were expected to increase over time. The power facilities that qualified under PURPA signed contracts to sell their electricity to utilities at rates specified in these avoided costs.

Independent power developers have had federal tax advantages for renewable energy projects since the late 1970s. Utilities, by contrast, frequently did not have such advantages. The tax advantages have included a 10 percent business capital investment tax credit (available to any business making capital investments), an additional 15 percent credit for wind and solar power projects that vested over a five-year period; and a five-year accelerated depreciation schedule. Utilities also benefited from this accelerated depreciation schedule, but were given seven instead of five years to depreciate these assets. The combination of federal tax incentives and additional state incentives meant that, until 1986, developers actually might make a positive return on their investment from tax benefits alone. In 1986, Congress removed the business investment tax credit, reduced the 15 percent energy tax credit to 10 percent for solar and geothermal over a period of two years, and eliminated the tax credit for wind energy.

Since 1986, a number of incentives have been added and some have been extended to utilities under certain circumstances. The Federal Energy Policy Act of 1992 permanently extended the 10 percent investment tax credit for solar and geothermal projects, unless utilities build those projects. The Energy Policy Act also created a 1.5¢ per kilowatt hour (kWh) production tax credit for wind and certain biomass projects.[8] The only federal tax incentive that is not now available to utilities is the 10 percent tax credit for solar and geothermal facilities.[9]

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[8] The act also made utilities eligible for the credit.
[9] Blair Swezey, *The Regulatory Outlook for Renewable Electric Generation in the U.S.*, The National Renewable Energy Laboratory. Paper presented at Advanced Workshop in Regulation and Public Utility Economics, Sixth Annual Western Conference, July 7-9, 1993, pp. 5, 8.

State Incentives

A number of states offered enhancements to PURPA. States like New York and California offered specialized contract terms, sometimes called mini-PURPA, to renewable energy facilities. Sometimes these states required their utilities to pay more than their avoided costs to attract renewable energy technologies.[10]

Moreover, many states offered property, income or other tax incentives to encourage renewable energy. California, more than any other state, offered generous incentives to renewable energy developers. These state incentives, combined with the federal incentives, made it worthwhile for equity investors to put money into a renewable energy power plant for the tax benefits alone.

Effects of Incentives on the Renewable Energy Industry

Before the 1986 federal tax reforms, generous incentives spawned many renewable energy facilities. To a large degree, they also were responsible for spurring the incredible improvements in technology and reductions in cost that made the technologies more commercially viable by the early 1990s. On the other hand, the incentives also attracted some producers who were concerned only with tax benefits. In parts of California, one may still see fields of inoperable wind turbines that worked only occasionally, even immediately after construction. These unsuccessful projects left a black mark on a number of renewable energy technologies. When the tax benefits expired, the incentive to maintain or install new technologies to upgrade the power plants often expired with them. These tax incentives shaped the early industry.

In states such as California that offered long-term contracts tied to long term predictions of energy costs, some renewable energy companies have experienced difficulty, as well. Companies that built power plants under the assumption that their revenues would increase over time were distressed to find the price of energy actually decreasing in the mid-1990s. Those prices decreased for several reasons, not the least of which were plummeting natural gas prices. If energy markets had moved upwards, as predicted in the mid- and late 1980's, many "problem" energy projects would look like wise and healthy investments today.

Many regulations affect fossil and renewable energy power plants alike. For example, state utility regulators approve the contracts that utilities sign with power producers, and state regulators indeed approved many contracts with renewable energy power producers in the late 1980s and early 1990s. Yet, it is usually more expensive to generate power from renewable energy sources than from natural gas and some other fossil fuels. As a result, many old power sales contracts now are priced above today's market prices for electricity, and some utilities have asked their regulators to let them renege on those contracts. This impact of this problem is not isolated to renewable energy resources, however. From the perspective of the financial community, these actions question the sanctity of the contract and add a new risk to energy project finance and power contracts for both renewable and fossil energy sources. This, and the direct effect of incentives on the renewable energy industry are tremendously important issues that not be dealt with in detail in this report.

Environmental Regulations

[10] New York and California have since changed their policies, and no longer offer the special rate or contract terms for power generated from renewable energy resources.

Environmental regulations and the way that power plants choose to comply with those regulations have a tremendous effect on renewable energy power plants too. These power plants operate in an industry that deals with a host of federal and state regulations. All types of power plants--renewable energy plants included--must deal with state and federal utility regulators, with environmental regulators, and with siting boards. Many must deal with local regulators as well.

The Power Plant Should Not Be Located Too Close to Population Centers or Points of Environmental Interest

Siting power plants near population centers or locations of particular interest can be difficult. Moreover, the emissions from power plants or their effect on the natural environment can subject them to public scrutiny. Such scrutiny can attract the attention of environmental regulators. The environmental regulators may require capital investments to reduce emissions, or noise, or to make the plant less conspicuous in the landscape.

One geothermal plant in the northwest has encountered considerable siting problems because it was located near a lake and was causing public concern that the lake would be adversely affected by the geothermal well drilling.

Developers Must Have a Plan for Disposal of Waste From Power Plants

Biomass projects, and particularly biomass projects that use mass burn technology can create waste disposal and air quality problems. Mass burn technologies do not separate fuel inputs, so that wood treated with potentially toxic stains or preservatives is mixed with untreated wood. The resulting toxic ash cannot be sent to landfills.

One power project assumed incorrectly that it would be able to use the local landfill to dispose of the ash from the wood and other material it burned. In fact, the ash contained toxins. The state environmental agency classified that waste as toxic and required the developer to send the waste to a special disposal facility. In addition to a state fine, the developer also had to pay substantially more for ash disposal.

Developers Must Be Aware of Potential New Environmental Regulations

One eastern United States power plant that burned rice hulls encountered problems with changes in environmental regulations that resulted from the power plant's own emissions. In this case, the emissions included silica from the rice hulls. Although the health effects of silica in this form are not clear, the silica was highly visible, creating a blue haze around the power plant. After protests from residents of the area surrounding the power plant, environmental regulators required that the developers install new scrubbers in the smokestacks at a considerable capital cost. This issue, like many described in this report, is avoidable with better planning. It is less likely to happen in an industry with more collective experience, although, aside from experience, few safeguards exist to prevent such incidents from recurring.

Technology

Renewable energy technologies have far fewer technological problems now than they did 10 years ago. Wind and solar technologies, in particular, are far more capable of producing electricity in a variety of weather and climatic conditions. The early industry, however, was marked by some critical technological failures. This is not a technical report, nor is it meant to substitute for the due diligence process that a financial institution engages in before it invests in any renewable energy project. This technical section focuses, instead, on areas that have posed significant problems for renewable energy projects. Not surprisingly, the greatest problems have occurred in the newest technologies. Thus, hydro technology--a comparatively simple and very old technology--has not encountered major technical problems. Fast developing wind technology, however, had some major equipment failures during the 1980s. The following discussion highlights several of the major problems and some ways in which the problems have been addressed.

Make Certain That Multiple Components Function Well Together and Are Appropriate to Their User

In many cases, power plants rely on components that work well in isolation from each other but pose problems when integrated. An example of this occurred with one reputable contractor that had received financing and a contract to build a power plant that used refuse derived fuel from municipal solid waste.

Refuse derived fuel plants do not have unusual components, but it can be difficult to make the components work together in a small power plant. In the rather gritty environment that the waste handling process creates, dust clogs the operation of the machines. In another case, a system used to separate large from small pieces of waste did not work at first. Conveyor belts that were not designed for municipal solid waste, for instance, continually caught large pieces of waste that were entering the power plant. As a result, a shredder had to be added to the waste processing system to reduce the size of the pieces entering the system. Odor control also can be a problem, and the plants must have an adequate ash disposal system.

In a similar case a developer built a project that used wood chips for fuel. Highly processed wood chips that are of uniform size are expensive. This developer decided to buy lower quality wood chips that were not uniform size, with bark, branches, tree limbs, 2x4s and rocks mixed together. The branches and tree limbs would catch in the conveyor belt, so the developer bought a wood chipper to make the chips into the same size. Although the plant eventually ran well, it required considerable retrofitting and new capital investments.

These plants are among today's better run and more profitable power plants. But the profusion of initial problems illustrate the complexity of a power plant that relies on a solid, mixed fuel to generate electricity. Such problems also illustrate the need to design compatible equipment and fuels early in the project, and to be aware that the developer may incur new, unexpected and potentially burdensome capital costs if those components are not appropriate to their function.

Assure That Machine Maintenance Is Cost Effective

As important as the capital cost of wind machines are the cost of operation and maintenance. As the utility scale wind industry increases its use of large turbines, it is becoming evident that the use of many small machines during the early years of the industry was probably not a cost effective way to spend operation and maintenance dollars.

One developer had guaranteed that a wind project would be available to produce electricity 90 percent of the time. But the technology was new and occasionally troublesome. For the 318 turbines in the wind farm, the developer maintained, at one time, a crew of 18 maintenance personnel. The cost to maintain the turbines added approximately 8 cents per kilowatt hour to the cost of producing electricity from the turbines. The developer, after resolving many of the problems in this early wind farm, reduced the maintenance crew to only eight people.[11]

Operation and maintenance expenses were an important and often difficult problem for the industry to overcome. As wind turbine technology has improved, the number of people required to maintain wind farms has decreased, as are the number of serious problems that the developers encounter. Typical operation and maintenance expenses for a new wind farm now are 1 cent or less per kWh on a large wind farm, and up to 2 cents per kWh for a smaller wind farm. These figures vary depending on certain circumstances. On a wind farm with larger turbines, the developer can spread fixed expenses over more kilowatt hours. Therefore, operation and maintenance expenses are higher on a per kWh basis for small wind farms. It remains that many small machines on a wind farm also mean more rotors, generators, gearboxes and other components for each kWh of electricity produced. Early wind projects demonstrated that too many small machines can require too much maintenance per kWh.

Unrealistic operation and maintenance schedules also plagued the early turbines. A number of early machines used “lifetime” gear lubricant that should have been changed every six months. Such lubricants are now far better attuned to the needs of wind turbines.

Wind Turbines Should Be Capable of Operating In Turbulent Wind Conditions

The best places to put wind turbines are the windiest places, hardly the places where most types of equipment would be. Both wind and weather place a tremendous strain on the turbines. Wind turbine developers have had to learn how to build machines that continue to work in turbulent, icy or other strenuous weather conditions. The early wind industry witnessed a number of U.S. developers using components that were not well suited to turbulent wind conditions. The flexible turbine blades struck their tower and became fatigued at critical points in their structure.

A number of other problems plagued the early wind industry, most of which have been resolved. The early industry often used “off the shelf” components, such as gear boxes, that had not been designed for the stresses that heavy and turbulent winds can place on a wind turbine. These components failed, leading the turbine manufacturers to adopt sturdier components that had been designed specifically for the wind industry.

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[11] Hubbard et al., *Advances in Solar Energy*, “Wind in Hawaii,” p. 450.

In Hawaii, for instance, developers predicted a 48 percent capacity factor for one wind farm. The actual capacity factor was only 18 percent. A mismatch of the operating characteristics of the wind turbines to the wind resource was partly responsible for this problem; the turbine was designed to begin turning at wind speeds that exceeded the average wind speed in the area. A great deal of the difficulty resulted, however, from mechanical problems that repeatedly occurred on these wind turbines. The turbines were, incidentally, the first of their kind; the manufacturer had never installed them outside its own test site.

The gearbox was damaged during strong gusts of wind. It had been built to accommodate more constant winds, not the wrenching of strong gusts that were common in the area. The gusts also stressed the bolts that attached the blades to the rest of the machine. Some blades actually were thrown off during gusty winds. Some other parts of the turbine, such as the bearings, deteriorated far faster than the developer expected. These and other maintenance problems added as much as 2 cents per kWh to the cost of operation.

Responding to the California incentives, for instance, many European companies rushed to build wind turbines in the state. Unfortunately, the strong California wind gusts were not reflective of the European experience. The European turbines suffered some major equipment failures before manufacturers developed equipment that could withstand this volatile wind resource.

The wind industry has developed new and better machinery to deal with many of these problems. Gearboxes, bolts, bearings and blades now are built to sustain large gusts of wind. Above a certain speed, the turbines shut down to protect against wind gusts. The industry still is examining the effect of ice on the power producing capacity of wind farms. This issue remains an important question in parts of the northeastern United States.

Today, with new technologies that address some of the early mechanical problems, wind turbines in a new power plant are available to generate electricity more than 95 percent of the time. Taking into account the amount of time the wind is strong enough to turn turbines, the wind plants have the capacity to generate electricity approximately 25 percent of the time, compared to 7 percent only 10 years ago.

Be Cautious of New and Untried Systems and Monitor Closely New Applications of Existing Technology

Most utility scale renewable energy projects will be financed through the project finance market. This project finance market is set up to work with established technologies, not with new or untried technologies.[12] Many investors in project finance markets have been willing to invest in some new applications of established technologies or modifications of existing technologies. Sometimes investors and lenders have been rewarded for these risks; at other times they have suffered.

Solar thermal applications, for instance, produce power so long as the sun shines. As a result, a company lobbied its regulatory commission to be allowed to use supplemental gas firing for 25 percent of the time. For example, if it generated 100 million kWh, up to 25 million of those kWh could be generated with gas.

The company installed an advanced version of a radiant gas heater technology--essentially, a large gas-powered heater to supplement the solar collectors. The heater was much larger than any previously built. This combined technology did not work as well as predicted; the gas technology failed, although the solar collectors performed just as they should have.

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[12] Less established energy technologies would more likely be financed with more expensive venture capital funding.

Understand the Technology and Its Costs

One biomass project in the western United States built in the mid-1980s was funded at approximately $4,000 per kilowatt instead of the then-standard $2,000 to $2,500 for a biomass facility. Instead of investing $100 million to $110 million in the project, the lender invested more than $200 million. This mistake was largely the result of the lender's misunderstanding of the technology and its costs. As a result, the group signed a deal for an overpriced project.

A decade after that project was financed, lenders have established methods to finance energy projects. The individuals in those organizations have, as a rule, become far better educated about the costs of biomass or other renewable energy projects. It is unlikely that a lender today would find itself in the situation described above. A risk remains, however, because such problems are avoided mainly through "institutional memory." With fewer new domestic biomass projects being financed, that "institutional memory" could weaken or disappear.

A Concluding Issue: Avoid Projects with Both Technical and Financial Difficulties

Renewable energy projects involve technology with applications that are either novel or represent a substantial modification of an existing application. The financial markets were receptive to alternative energy project in the 1980s and early 1990s because lucrative power contracts and tax incentives were designed and made available to promote such projects. The powerful combination of access to capital and governmental encouragement brought many developers and investors into a new market. The resulting projects varied in quality depending on the sponsors' technical or financial strengths. All technological or financial innovations are destined to require a recalibration at some time early in their development. The confluence of technical and financial stress often is hard for a project's finances to withstand. Investors and lenders are leery of the thinly capitalized company that is attempting to develop a large project using an unproven technology with large tax benefits for the equity participants. A properly structured project generally can withstand some stress if the participants are committed to the project. Even committed parties rarely can revive a project that has encountered both technical and financial difficulties simultaneously. The combination of two problems--which require both financial and technical management attention--appears to consistently doom projects.

Many financial institutions can structure new investments to accept some risk in either the financial or technical area, but not in both. Because, by definition, a new technology would have few people expert in its application, many institutions have taken a greater financial than technical risk. The role of a bank or institutional investor is to take some financial, contractual and process risk in financing a project. These lenders are not rewarded by the current interest rate levels to take technological risk.

Conclusions

Investors with short-term interests dominated the renewable energy industry during the early 1980s. Motivated by short-term tax considerations, these investors and developers had little incentive to maintain the wind, solar or other renewable energy projects once they had earned the return they expected from the first few years of the projects. These early tax incentives attracted many new companies to invest in the industry. Some have survived the demise of the tax incentives. These companies remain as the stronger developers in the industry. As the early tax incentives disappeared, so did the less credible developers.

The regulatory system also has changed since the early years of the renewable energy industry. A number of considerations remain relevant to the regulatory climate in which renewable energy power plants operate. State rate regulators play a critical role in approving or disapproving the costs of the electric utilities that purchase power from renewable energy power plants. States in which the regulators appear likely to disapprove utility expenditures on renewable energy have proved to be somewhat less hospitable for renewable energy projects. As important, though, have been the state environmental regulators. Regulating both the disposal of waste and the air emissions from some renewable energy facilities, the environmental regulations play an important part in the success or failure of renewable energy facilities. Those facilities that did not appropriately plan for the effect of the power plants on visibility, air quality or waste disposal system often have had to invest unexpectedly large amounts in remediation measures.

To some extent, technological issues have been responsible for putting renewable energy projects on the financial institutions' "watchlist" of projects. Wind, in particular, has developed new capabilities that have allowed the turbines to operate in harsh or mild wind conditions--and to produce power more regularly than before. Again, many early problems were related to tax incentives that encouraged developers to focus on building--but not maintaining--wind projects. Some projects simply were poorly designed for the wind environment in which they were operating. Many technological issues have applied to the newest utility scale technology, wind, rather than to other, more conventional technologies such as biomass or hydro.

Energy resources--whether wind, sunlight, biomass, water or hot steam--have been the most significant factor in the problems that renewable energy facilities have encountered. Unable to sign long-term contracts for wind, sunlight or biomass, developers--and the lenders and investors that provide their capital--must rely on assessments of the resource that will be available for the power project. The early years of the renewable energy industry were characterized by inadequate resource assessments. Those who invested in renewable energy projects continue to view resource assessment risk as an important factor. The wind industry, in particular, has made tremendous strides in assessing the wind energy resource at proposed sites. Other renewable energy industries, particularly biomass, should benefit from the mistakes of the 1980s. The most important lessons to be learned from a decade of renewable energy resource development have had to do with the assessment of the resource.

Appendix A

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Financing Renewables: How It Happens

The developers, bankers, and other lenders and investors who finance energy projects often deal in the "private placement" market. That is, they negotiate privately with each other instead of issuing public debt. The private placement market differs from the public debt market because it involves investors, lenders and borrowers with special requirements. Typically, the borrowers who use the market are small[13] and are raising money for projects about which not much information is available.[14]

Private placement debt usually carries a higher interest rate than debt issued for the public markets. This higher interest rate can be justified for large debt issues, but are harder to justify for smaller issues. Public debt, by contrast, is expensive to issue, carriers a lower interest rate, and can be used to finance projects about which there is a great deal of information available.[15] Private placements also tend to be smaller than public bond issues.[16]

Borrowers can gain access to the private placement market through the "project finance" process. Project finance relies on revenues from specific projects to repay lenders and provide returns to equity investors. It does not rely explicitly on the credit of the project's sponsors or developers but, instead, on the return and risk of the project itself. Project finance also is usually non-recourse; that is, if the project cannot meet its obligations, the lenders may look only to the project’s assets and cannot pursue the developer’s or sponsor's assets to pay back the project loan.[17] The process allows borrowers to raise money for large, capital-intensive projects like energy projects. Project finance also is a common financing practice in other capital-intensive industries like mining or shipping and in some major construction projects.[18]

Developers find project finance structures useful for a variety of reasons. First, the credit appraisal of individual projects may be more favorable than the appraisal of the developer itself. Projects become possible that would not be financeable based on the developer's financial profile. Second, it leaves the sponsors free to pursue several projects simultaneously, each based on its own merits. Project financings stand alone, so the failure of one project will not cause failure of another. Third, major corporations that are capable of financing projects through other means may choose to use

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13   The small size of these projects may not justify the high fixed costs of registration, etc., in the public markets. Lenders must study each project's revenues, expenses and risks very carefully before investing.
14 Mark Carey, Stephen Prowse, John Rea, Gregory Udell, *The Economics of Private Placements: A New Look*, A monograph from the New York University Salomon Center series: *Financial Markets, Institutions and Instruments*, Blackwell Publishers, Cambridge, Mass., 1993, pp. 6-8.
15   Such information would be available through the Securities and Exchange Commission or other filings, trade publications or newspapers.
16 *Ibid.*
17 Scott L. Hoffman, "A Practical Guide to Transactional Project Finance: Basic Concepts, Risk Identification, and Contractual Considerations,"   *The Business Lawyer*, Vol. 45, November 1989, p. 182.
18 The English Channel Tunnel sponsors raised money for the gargantuan project through the project finance process.

project finance as a way to isolate the effects of the project's debt to equity ratio from its own balance sheet. Project finance also works to allocate risks to those who can best bear them. Construction risk is borne by the contractor who builds the facility, the risk that fuel prices will change radically can be allocated to the fuel supplier, etc. Project financing also can allow the participants to allocate the tax benefits of some projects to those who can best use them. Other financing techniques may not provide the same flexibility for the developer to invest in multiple projects.[19]

Project financing has disadvantages. First, it is typically expensive. Lenders require very careful due diligence engineering and financial reviews. This causes high transaction costs. Second, interest rates can be higher than for a typical direct loan. Finally, project financing also often involves restrictive covenants and supervision.[20]

A hypothetical example can best explain project finance for a renewable energy project and the cash flows involved in the process.

Project Finance: A Hypothetical Example[21]

Windy Development Corporation (WDC), a medium size independent power producer specializing in wind energy, has responded to a large utility's--Consolidated Public Service (CPS)-- competitive bid solicitation. WDC has offered to build a wind facility to supply power at a cost that is below the utility's avoided cost. CPS has accepted the bid at the price that WDC offered, and the two have negotiated a 20-year power sales agreement. WDC also has received all the permits it needs to build the wind power plant. It has completed the wind resource studies and has completed most of the engineering work necessary for the project. The engineering work has focused on identifying the size and type of wind turbines to use, based on cost/benefit analysis and using site-specific wind speed data.

WDC also has completed a financial model showing how the project will incur expenses and generate revenue over its life. WDC now needs money to continue. Because it does not have the internal capital to build the facility, it uses the project finance process to raise $50 million.

WDC secures an investment banker located in midtown Manhattan to serve as a guide through the process, to help structure the deal, and to make contact with the potential lenders and investors. This investment banker will charge a fee for her work, but will be invaluable because WDC does not have the necessary contacts to secure the money to build the project. After a close examination of WDC and the project, the investment banker feels comfortable that WDC is a reliable project sponsor/developer and that the project will perform as WDC says it will. The investment banker then takes the project to a number of banks.

One large commercial bank, Commercial One, is extremely interested in becoming the senior lender for the project. Its close appraisal of the project focuses on a few specifics.[22]

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[19] *Ibid*., p. 187.
[20] *Ibid*., p. 188, and Personal Communication, David Miller, Sithe Energies, December 1993.
[21] To emphasize the obvious, none of the names used here represent real companies.
[22] In this hypothetical example, we assume that Commercial One is the only senior lender. Other financings may have multiple senior lenders with complex agreements between them. Commercial One, like all the companies named in this hypothetical example, is itself hypothetical.

Power Purchase Agreement. Commercial One examines the power purchase agreement. Like all the investors and lenders involved in the project, the bank uses the power purchase agreement as assurance that it will receive its interest and principal payments. The bank generally will not finance a project unless the term of the power purchase agreement is at least as long as the term of the loan. Commercial One is a typical commercial bank; it offers a three-year "construction loan" (the three-year loan used to finance construction of the project) plus a 15-year "term loan" that begins once the project is built and producing power. Other lenders, such as insurance companies, may offer longer term loans.

Commercial One also examines the credit history of CPS to make sure that CPS can meet its obligations to buy power. The bank also will look at CPS' history; for example, its record of negotiating or attempting to renegotiate existing power contracts. The CPS/WDC agreement must, like any legal contract, be practical for all parties, enforceable and not likely to change.

Unlike cogenerators, who produce useful thermal output that can be sold to a steam host, this renewable energy project produces only electrical energy. As a result, the power purchase agreement is the sole source of revenue for the project, and the bank scrutinizes it in detail. The following provisions are particularly important.

Price. Commercial One regards the price per kilowatt hour of electricity in the power purchase contract as the primary indicator of the project's ability to meet its financial obligations. Commercial One examines the risk that the price will change substantially in the future and the ability of the revenue stream to meet the financial obligations of the project. Contracts that pay a fixed price for electricity make Commercial One most comfortable. Contracts that pay a variable price for electricity are less attractive (and may result in the financing contract having higher interest rates).

Commercial One may also look at the electricity price in relationship to current or future prices. A very high price for electricity could make Commercial One apprehensive about future contract challenges by utilities. Some utilities have successfully renegotiated such contracts years after they were signed, claiming that they were too expensive and that they were, as a result, making electricity more expensive than necessary.

Experience and Reliability of All Parties. Although project finance does not rely explicitly on the credit of the developer, Commercial One still makes an important qualitative judgment about whether WDC appears ready and able to build the project and whether the project operator also has a financial incentive to continue with the project.[23] One banker noted that she liked to reflect on whether she could comfortably introduce the loan applicant to her chairman. If she did not feel comfortable with that idea, she would be less inclined to put money into the developer's project.[24]

Milestones and Security. Commercial One looks at the milestones for completion of various tasks and the security payments that the contract requires as a way to manage risk. The bank feels comfortable only if those milestones appear reasonable and will not interfere with the ability of the project to meet its financial obligations. As with the other provisions, a difficult schedule of project milestones or large security payments paid to the utility will make Commercial One view

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[23] P. Nevitt, Project Financing, Euromoney Publications (4th ed., 1983), p. 4.
[24] Personal communication, Deborah Gravinese, Toronto Dominion Bank, May 1994.

the project as more risky. Additional risks translate into higher interest rates in the financing contract.

Commercial One would like to have complete confidence that WDC will collect the revenue that it has promised. Any event that might interfere with the receipt of the predicted payments is a source of risk to Commercial One. If certain events can diminish the expected revenue, then WDC can take steps to ensure that either the events will not occur or that the project's economics are not terminally affected by the event. If, for example, performance tests are required by the utility as a prerequisite to full payments, WDC can incorporate redundancy into the equipment design and provide a reserve against operational contingencies that would lead to the failure of a performance test. Similarly, if power revenue can vary with the utility's avoided cost, WDC may need to set a minimum rate by negotiating a contract floor price or try to otherwise “hedge” the variability of the pricing.

In essence, WDC will need to “insure” against the events that could lead to diminished revenue. The cost of such insurance is not necessarily related to the cost to the utility of the event. Any remaining uninsured events represent risks to Commercial One. For higher risks, such as the use of new technology, Commercial One will demand a higher interest rate as a risk premium. Some major risks are uninsurable and unacceptable and may result in a project that Commercial One will not finance.

Debt Coverage Requirements. Commercial One examines the power purchase contract and other risk elements to decide if the project has the necessary coverages. Coverage refers to the ratio of cash flow to debt service. “1.5 times coverage” means that cash flow is 1.5 times the debt service amount. Lenders will demand a higher return for greater risk. Some lenders may even search out projects that are perceived to carry greater risk, because those projects can provide a greater return. Some lenders blend renewable energy investments into their portfolio of projects as part of their portfolio allocation process. Some will also take subordinated debt risk in a particular project if they consider the risk adjusted return acceptable.[25]

Fuel Source. WDC presents its wind resource assessments to Commercial One as proof that the wind resource is adequate. Commercial One, in turn, gives those assessments to its independent engineer, who examines them in detail. If the engineer agrees that there is enough wind to spin the turbines at the required rate and frequency, Commercial One will continue to structure a deal. In the case of other technologies, sponsors must show that they have a long-term gas contract, an adequate supply of wood or other biomass, or that the wind, solar or water resource is adequate and dependable.

Permits. Developers must secure all permits that can be secured before the plant begins operating. Investors or lenders will not invest in a project without some assurance that the developer has secured all the necessary permits to build and operate the facility.

Developer or Sponsor Financial Interest in the Project's Success. Commercial One is considering whether to entrust millions of dollars to WDC over a 15- to 18-year period. Despite power sales contracts, secure energy supplies and all the permits, lenders like to see that the developer has a

[25] Personal communication, Phil Huyck, Senior Vice President, Trust Company for the West. In the event of a default, subordinated debt holders have a smaller chance of getting their money back than do senior debt holders.

financial incentive to keep the project in operation and to meet the financial projections upon which the loan is proffered. That incentive might be, for instance, in the form of an equity interest in the facility.

Regulatory Environment. Commercial One examines the regulatory climate in which WDC proposes to build its wind farm. In WDC's hypothetical case, Commercial One notes, among other issues, that regulators appear to support the contracts that power producers have negotiated with utilities. As a result of mid-stream changes in some government incentive policies, many in the financial community are now leery of basing any loan or investment on a promise of a government incentive or regulatory requirement.

Technology. Commercial One hires independent engineers to examine the technology and its ability to produce power given the wind resource assessment. In this hypothetical case, WDC has selected wind turbines made by a major turbine manufacturer. Commercial One finds that the manufacturer has turbines with a proven performance record in similar climates. Commercial One also finds that the wind resource studies appear reasonable and that the amount of wind at the site will, indeed, be sufficient to produce power.

Construction Costs and Site Lease. Commercial One looks at the ability of the developer to build a working power plant within the proposed budget. A prevalent problem with power plants--particularly those that use new technologies--is that they do not work as they were intended, and they require additional capital investment to correct the problems. This additional capital comes from lenders or equity sources, but at higher financing costs for the project. Commercial One also assures that WDC has secured the rights to build on the land.

The Risks. Commercial One appraises the project's risks. Two examples are:

- Will there be significant community opposition to building the windfarm?
- Is the regulatory climate supportive of the project and the power purchase contract?

Commercial One determines that the project can meet the financial projections, that the wind resource studies are reasonable, that the technology will work, and that the risks of the project are not too great. At this point--signing the contract--Commercial One asks WDC to provide an initial commitment fee of between \$50,000 and \$100,000. Commercial One also asks WDC to provide copies of draft and final engineering studies and construction contracts, operation and maintenance contracts.[26]

Finally, Commercial One is satisfied with the project. The two parties close their agreement. The agreement includes many points, but a key attribute will be the control of Commercial One's exposure. WDC and its contractors want to make money. This will be facilitated by dictating who gets how much money at what point. Some the key points of this agreement follow.

Spreads. Commercial One expresses the interest rate on the loan as a spread over some generic but widely accepted interest rate. This might be the London InterBank Offer Rate (LIBOR), the rate at which banks can loan money to one another on the international market. The spread will reflect the level of risk that the bank feels it is assuming--greater risk means greater spreads. The spread is the interest over a certain published interest rate. For example, a rate of LIBOR (6 percent) plus a 2 percent spread would equal 6 percent plus 2 percent, or 8 percent.

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[26] Gravinese, *supra.*

Equity Requirements. Commercial One asks WDC to raise 20 percent of the necessary $50 million financing from equity investors. The amount of equity that senior lenders require also varies with the level of risk determined by the bank and from project to project. The amount of equity that senior lenders require also varies over time. In the mid-1980s, for example, hydro electric projects needed to raise 20 percent of their costs from equity. By the late 1980s, they needed to raise almost one-third of their requirements from equity sources. The current equity requirement for hydro has now decreased to approximately 15 percent. [27]

Reserves. Reserve accounts are used to cover the risk that a project might temporarily be unable to meet its financial obligations. In this case, Commercial One asks that WDC pay into the reserve account by drawing upon the loan received when the project began operation. Reserve accounts also can be filled through project revenues. The greater the risks felt by the lenders, the greater the reserve requirements will be.

Coverages. Commercial One asks that the WDC wind power project maintain a certain ratio of cash flow[28] to debt obligations. Falling below that ratio would serve as a warning to Commercial One that the project is performing poorly. Consistent problems will bring Commercial One's "workout department" to meet with WDC and restructure the loan. The workout department deals with loans and projects that are having trouble meeting their repayment obligations. Riskier projects are required to maintain higher coverage ratios.

Distributions to Equity Investors. The loan agreement usually will dictate when and under what circumstances WDC can distribute cash to the project's equity investors.

At closing of the $50 million loan, WDC is responsible for paying a bank fee of approximately $500,000 (minus the $50,000 to $100,000 paid at signing) and the bank attorney fees of approximately $600,000 (these can be as much as $1 million). WDC also is responsible for paying approximately $50,000 for the bank's engineers to examine the project. WDC, like many developers and sponsors, pays these upfront fees with the first draw on its loan.

WDC contractors then begin work on the project. A monthly construction progress report is prepared by WDC. Commercial One engineers review the report and WDC's progress, and approve a monthly draw on the loan until the agreed upon completion date for construction. This can be up to three years; for a wind project, it is more likely between one and two years. At the end of the construction loan period, Commercial One will have invested $50 million, or 100 percent of the financing. WDC now must repay the full value of the $50 million construction loan[29]

Security. The loan will be secured by a pledge of all tangible and intangible assets associated with the power plant--all property, the plant and plant equipment.

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[27]Personal communication, Steve Chweiko, Chief Financial Officer, Adirondack Hydro, New York State. January 1994.

[28] Cash flow is defined here as earnings before interest, taxes, depreciation and amortization.

[29] Gravinese, *supra.*

The Term Loan.[30] WDC repays the construction loan with a $40 million term loan from Commercial One[31] and $10 million from its equity investors. In essence, 80 percent of the three-year construction loan is converted to a 15-year term loan. The length of the term loan typically is 15 years for commercial banks and longer for other lenders like insurance companies. The length of this term loan will never be longer than the length of the power purchase contract. The only exception to this rule occurs when there is a good deal of assurance that the plant will be able to market its power successfully on the open market. The trend in today's market toward short term power purchase commitments will make it harder for renewables, which benefit from long-term contracts to amortize their capital costs, to secure financing.

Commercial One will now receive quarterly payments from WDC. The equity investors will receive cash distributions periodically, but only after Commercial One, the company operating the project, any reserves, and the subordinated lenders have been paid. Typically, the equity distributions will be made only if the project is providing a coverage ratio of 1.25 or more. The equity investors assume the greatest risk in the project, but could also receive the highest returns.

This project financing has given WDC $50 million over 18 years from a combination of equity investors and a senior lender. Other project financing can be more complicated, involving numerous lenders with varying levels of priority and several equity investors, but the processes are similar.

Where the Money Comes From

Three types of organizations provide or arrange financing for both renewable and conventional energy projects: investment banks, lenders and investors. Each has its own interests, its own time over which it wants to recover its money and its own restrictions. It is worth reviewing each of these parties and their roles in the financing process.

Investment Banks. Investment banks arrange financing. They do not usually provide the money. Instead they broker deals between the people who want money (the project sponsors) and the people who want to lend or invest it (the banks or other financial institutions). The investment banks earn their money from fees on the transactions they broker.

A good investment banker should look at a project from the perspective of those who may invest in it. Investment bankers therefore need to understand the objectives, desires and restrictions of potential investors. Investment bankers may be the first contact for a project developer. Typically, an investment banker analyzes a project and, if it looks viable, will contact the people who are likely to invest.

Two types of investment banks are important in the energy project finance field: boutique and large investment banks. These banks are distinguished by their size and specialty. Boutique investment banks generally deal with smaller transactions, while larger investment banks handle transactions that generate larger fees to cover their often higher overhead costs.[32] Many renewable

[30] The term loan also is referred to as take-out financing or permanent loan.
[31] It is typical for the same lender to offer the construction and the term loan.
[32] The larger banks frequently have higher overhead costs in part because of larger offices with many support staff. Many so-called boutique investment banking firms have small offices with very small support staffs.

energy projects, because they are smaller than gas, oil, or coal fired facilities, will be brokered by the boutique investment banks.

Commercial Banks and Other Institutional Lenders. Commercial banks loan money to project developers through departments that specialize in project finance. Many foreign banks provide funding to independent power producers. Such lenders include Banque Paribas, Swiss Bank Corp., Canadian Imperial Bank of Commerce, Toronto Dominion Bank and others. Domestic lenders such as Prudential Power Funding, a unit of the Prudential Insurance Company, and GE Capital, a unit of General Electric, also are major lenders in this area.[33]

Project finance bank lenders typically lend for approximately 15 years, although institutional lenders such GE Capital or Prudential Power Funding may offer a longer term. The approach each of these senior lenders takes in reviewing prospective projects includes an assessment of the risks and benefits of the project.

Subordinated Lenders. Subordinated lenders are a hybrid of equity investors and senior lenders. Subordinated lenders--such as the pension management firm Trust Company for the West--will be paid after the senior lenders but before equity investors. Their loan is at greater risk than that of the senior lenders. To compensate for the higher risks that they accept, the subordinated lenders receive a higher interest rate and, perhaps, some participation in the equity upside. Subordinate lenders use subordinated loans to fill out the riskier--and higher return--portion of their portfolio.[34] Because they are lenders, not equity investors, however, they are paid before the equity investors and are senior to the equity in the event the project fails. If a project does fail, subordinated debt holders are unlikely to benefit from their priority to the equity. Even the senior debt is unlikely to be covered.

Equity Investors and Green Funding. Equity investors typically provide 10 percent to 25 percent of the project's costs and assume the greatest risk because they are last to be paid. However, they are compensated for taking the financial risk; pretax equity rates range as high as 25 percent.[35] Equity investors approach project finance from a very different perspective than do lenders. Equity investors look carefully at the tax benefits of investing in energy projects. Thus, the tax credits, tax deductions and accelerated depreciation schedules that accrue to renewable energy projects are germane to the equity investors. The restrictions that the 1986 federal tax reforms placed on tax advantages, for example, had a profoundly negative effect on the amount of equity available for renewable energy facilities.[36]

Fuel suppliers, equipment vendors or contractors may supply project equity. Often motivated by the desire to spur the market for their products, these investors frequently participate in project finance.[37] Another group, Energy Investors Fund, has used money from utility subsidiaries, insurance companies and pension funds to establish these equity investment funds with more than $325 million for energy and infrastructure projects. This group places particular emphasis on

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[33] Independent Energy, Financial Rankings from March 1992 and 1993, Milaca, Minn. Also based on discussions with developers and members of the financial community.
[34] Personal communication, Phil Huyck, Vice President, Trust Company for the West, December 1993.
[35] Chweiko, *supra*.
[36] Personal communication, Blair Swezey, National Renewable Energy Laboratory, April 1994.
[37] Hoffman, p. 192.

alternative energy projects. Another example, Caithness, is a financial institution that specializes in thermal projects and has raised equity from wealthy individuals. Caithness specializes in "green" products and projects and secures money (or “green funding”) from people who wish to invest in environmentally beneficial projects.[38]

[38] Personal communication, Hiram A. Bingham, Vice Chairman, Caithness Resources, Inc., January 1994.

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